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16. ABSTRACT The article summarizes information presented at the 1989 Joint EPA/EPRI Symposium on Stationary Combustion NOx Control, March 6-9, 1989, in San Francisco. The symposium was attended by more than 400 representatives of 40 domestic and 10 foreign utilities, government agencies, research and development organizations, and boiler manufacturers from the U.S. and 14 other nations. More than 60 presentations focused primarily on developments in combustion NOx technologies, selective catalytic reduction (SCR), advanced combustion technologies, hazardous and municipal waste incineration, combined NOx/SO2 control processes, and fundamental combustion research. Introductory reports covered the NOx regulatory status in the U.S. and abroad, the U.S. DOE's Innovative Clean Coal Technology program, and NOx measurements and environmental effects. The article focuses on new results and understandings since the last (1987) meeting, as they pertain to electric utility power plants and other combustion sources. Key points discussed included the dramatic increase in full-scale retrofit demonstrations of low-NOx combustion modifications on pulverized-coal-fired boilers; full-scale operating experience in Japan and Western Europe with SCR, and research and development to assess application in the U.S.; and development of NOx controls for utility boilers.

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Nitrogen Oxides	Measurement	Stationary Sources	07B	
Combustion	Electric Power Plants	Hazardous Waste	21B	10B
Fossil Fuels	Boilers	Municipal Waste	21D	13A
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Stationary Combustion NO_x Control

A Summary of the 1989 Symposium

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This paper summarizes information and results presented at the 1989 Symposium on Stationary Combustion NO_x Control, held March 6–9, 1989 in San Francisco. Cosponsored by the Electric Power Research Institute (EPRI) and the U.S. Environmental Protection Agency, (EPA) the symposium was the fifth in a biennial series.

The 1989 Symposium on Stationary Combustion NO_x Control was attended by over 400 individuals representing 40 domestic and 10 foreign utility companies, as well as by government agencies, research and development organizations, and boiler manufacturers from the United States and 14 other nations. Over 60 presentations were made, focusing primarily on developments in combustion NO_x technologies, selective catalytic reduction (SCR), advanced combustion technologies, hazardous and municipal waste incineration, combined NO_x-SO_2 control processes, and fundamental combustion research. The stage was set for these discussions by introductory reports on NO_x regulatory status in the United States and abroad, the U.S. Department of Energy's Innovative Clean Coal Technology program, and NO_x effects on the environment.

In discussing the significant findings reported at the symposium, this paper focuses on new results and understandings since the last meeting in 1987[1] (JAPCA July 1987) as they pertain to electric utility power plants and other combustion sources. Key points discussed included the dramatic increase in full-scale retrofit demonstrations of low-NO_x combustion modifications on pulverized-coal-fired boilers; full-scale operating experience in Japan and Western Europe with selective catalytic reduction, and R&D to assess application in the United States; promising results with selective noncatalytic reduction using urea injection; and the substantial amount of development activity in the United States and abroad to optimize NO_x controls on oil- and gas-fired boilers.

D. Finnegan, counsel for the House Energy and Commerce Committee, opened the symposium as keynote speaker by acknowledging the impressive amount of research and development under way to control NO_x emissions, and by encouraging the utility industry and others spearheading this work to make legislators aware of their accomplishments. The potential role of NO_x emissions in affecting tropospheric and stratospheric ozone, in contributing to acid rain, in impacting human health and visibility, in forest degradation, and in global warming is receiving considerable attention nationally and internationally, and pressures for more stringent NO_x control can be expected to grow as bills to reauthorize the Clean Air Act move through Congress.

Extensive research is currently under way in each of these areas to determine what effect, if any, NO_x emissions have on the environment, and to demonstrate technologies to more efficiently and cost-effectively control NO_x emissions. Recent announcement of awards of funding under the second phase of the U.S. Department of Energy's Clean Coal Technology program (CCT-2) indicates the importance being given to NO_x control in the United States.[2] Of the 16 projects selected for funding (13 of which include utility involvement), six are NO_x related. Considerable activity is also under way in Europe and Japan.

The potential role of large stationary combustion sources in contributing to stratospheric ozone depletion and to the buildup of greenhouse gases has been raised as an issue by postulations that combustion sources emit large amounts of nitrous oxide (N_2O). To test these claims, EPRI developed an on-line N_2O analyzer. While calibrating this analyzer, researchers determined that N_2O was being made in the sample flask in the presence of moisture and sulfur, and not in the flue gas.[3] Using corrected sampling techniques, EPRI, EPA, and others determined that direct N_2O emissions in flue gas from conventional pulverized coal-fired boilers were less than 10 ppm, versus the 100 to 200 ppm postulated.[3,4] Subsequent testing is planned by EPA and EPRI to determine if N_2O emissions from fluidized-bed combustion (FBC) boilers are higher than from conventional pulverized coal-fired boilers, as has been suggested by experience in Europe. If so, operational changes or gas cleanup techniques will be evaluated to minimize these emissions. Research is also being initiated to assess the potential for N_2O formation in the plumes of large combustion sources or, subsequently, in the atmosphere.

Combustion Controls for Coal-fired Boilers

R&D to reduce NO_x emissions from stationary sources in the United States remains focused on retrofit combustion

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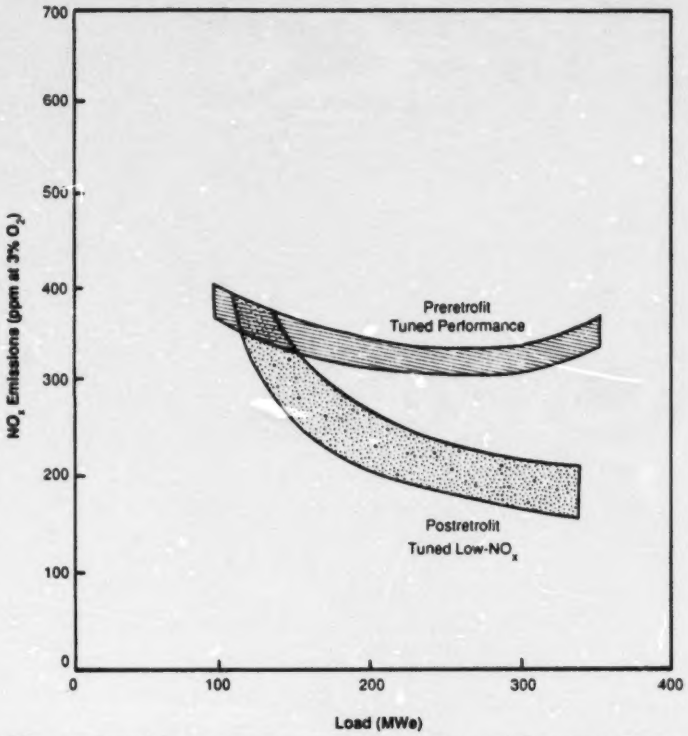

Figure 1. Comparison of preretrofit and postretrofit NO_x emissions data taken in testing a LNB system with OFA on a tangentially fired pulverized coal boiler. Source: Electric Power Research Institute.

modifications for conventional pulverized coal-fired boilers, which account for 70 percent of all U.S. utility NO_x emissions. Low-NO_x burners (LNBs) with overfire air (OFA) are the preferred approach for tangentially fired and wall-fired units. Reburning remains the only widely discussed option for cyclone boilers.

The presentations concentrated heavily on domestic and international demonstrations of full-scale retrofit low-NO_x combustion modifications now under way and planned. Demonstration activity has increased dramatically in recent years, especially in the United States, West Germany, the United Kingdom, Italy, and Japan, and represents an essential step in confirming the viability of combustion modification NO_x controls on a widespread basis. Emphasis on full-scale investigations was in sharp contrast to previous symposia, which focused principally on pilot developments.

Increased NO_x R&D activity in the United States—by government, utility companies, boiler manufacturers, and others—was also apparent. Recent commitment by Ente Nazionale per L'Energia Elettrica (ENEL) in Italy to combustion control technologies developed by U.S. companies for both coal and multifuel applications is indicative of the increasingly important role the United States is playing in developing and demonstrating combustion modification NO_x controls.[5]

Table I shows the major coal-fired combustion NO_x retrofit demonstrations under way and planned in the United States. As can be seen, 12 demonstrations will be conducted involving LNBs, OFA, and reburning on each of the four types of conventional pulverized coal-fired boilers in sizes ranging from 40 to 800 MW. The six NO_x-related clean coal technology (CCT) demonstrations alone represent a financial commitment by government and private industry in the United States totaling approximately $85 million.

The thrust of retrofit demonstrations is not only to quantify potential NO_x reductions in actual utility operating environments, but also—just as importantly—to determine what impact controls will have on boiler operation, performance, and maintenance. Investigations are focusing on issues related to combustion efficiency (e.g., residence time, mixing, unburned carbon levels), thermal performance (e.g., heat absorption, furnace exit gas temperature), and O&M (e.g., reliability, turndown, excess O_2, slagging and fouling, corrosion, instrumentation and controls, and fan requirements).

Early experience in applying combustion modification NO_x controls in full-scale units indicates, for example, that these technologies require tighter tolerances on air and fuel distribution systems than are typical of conventional burners. This is especially true in older plants where air and fuel systems can be worn or outdated. In many cases, operators considering low-NO_x modifications are simultaneously assessing the need to upgrade other boiler systems, especially air and fuel supply systems and their controls. This "integrated approach" increases retrofit costs, but is prudent from an overall cost and efficiency standpoint. Improved air and fuel systems, for example, can provide potential heat rate improvements through reduced excess air requirements. Moreover, this approach ensures that desired NO_x reductions are, in fact, achieved and maintained. Viewed from another perspective, when boiler upgrades and life extension programs are planned, combustion controls should be considered as insurance in the event more stringent NO_x controls are required.

Each of the four major U.S. utility boiler manufacturers described advances in LNB technology achieved since the last symposium. Babcock & Wilcox (B&W) presented developmental results of its new XCL tri-fuel (coal, oil, and gas) burner;[6] Combustion Engineering (CE) revealed development of its new concentric clustered tangential firing system, an outgrowth of, and lower cost alternative to, its pollution minimum (PM) burner;[7] Riley Stoker (RS) quantified improvements to the airflow capabilities of its controlled combustion venturi (CCV) burner, obtained with an improved register system;[8] and Foster Wheeler (FW) discussed application of new materials on its controlled flow/split flame (CF/SF) burner to avoid high-temperature corrosion problems.[9]

In each case, these advances represent incremental improvements to existing technologies, a trend reflecting the uncertain market for control equipment in the United States in the absence of new NO_x legislation, and limited new unit construction by U.S. utilities. In response to growing interest in refuse derived fuel and FBC, development of NO_x controls for these applications is moving ahead and was discussed by vendors at the symposium.

Tangentially Fired and Wall-fired Boilers

In the United States, Europe, and Japan, most utilities retrofitting combustion modifications for tangentially

Table I. Summary of major coal-fired combustion NO_x retrofit demonstrations in the United States.

Boiler type	Host and plant	Technology[a]	Size (MW)	Lead sponsor(s)[b]
Tangentially fired	Kansas Power and Light, Lawrence	LNB, OFA	350	EPRI
	Gulf Power, Smith	LNB, OFA	180	CCT-2, EPRI
	Virginia Power, Yorktown	LNB, OFA	170	EPA
	Illinois Power, Hennepin	Reburn	80	CCT-1, GRI
Wall-fired (circular burners)	Penelec/NYSEG, Homer City	LNB	600	EPRI
	Georgia Power, Hammond	LNB, OFA	500	CCT-2, EPRI
	Ohio Edison, Edgewater	LNB	100	EPA
	Central Illinois Lighting, Edwards	Reburn	120	CCT-1, GRI
Cyclone-fired	Ohio Edison, Niles	Reburn (gas)	100	EPRI, EPA, GRI
	Wisconsin Power & Light, Dewey	Reburn (coal)	100	CCT-2, EPRI
	City Water, Light & Power (Springfield, IL), Lakeside	Reburn (gas)	40	CCT-1, GRI
Wall-fired (cell burners)	Arizona Public Service, Four Corners	LNB	800	APS

[a] LNB = Low-NO_x burners; OFA = Overfire air.
[b] CCT = Innovative Clean Coal Technology Project—Rounds 1 and 2; GRI = Gas Research Institute; APS = Arizona Public Service. Host utilities are also major sponsors in all projects.

fired and wall-fired boilers are installing LNB systems incorporating OFA and low excess air.

One of the most significant findings of the retrofit LNB demonstrations reported at this symposium is the dominant role OFA plays in NO_x reduction. As a result, OFA could be appropriate as a stand-alone modification in some applications. Results show that up to 30 percent NO_x reduction can be achieved with conventional OFA by staging 10 to 20 percent of the combustion air. Capital costs for conventional OFA alone would be about $5/kW, versus $10 to $30/kW for LNB with OFA. These costs represent total plant investment, including all direct costs. Capital costs are a function of boiler capacity, decreasing with increasing size. Operating costs are believed to be relatively low, but need to be quantified.

Advanced OFA systems, which stage 20 to 30 percent of total combustion air, have been developed in Japan and are being investigated in the United States. These systems have the potential for over 30 percent NO_x reduction. Capital costs are expected to be about $10/kW.

NO_x reductions of up to 50 percent have been demonstrated with LNB systems incorporating OFA. Capital costs are in the range of $10 to $30/kW depending on site-specific factors such as furnace design, fuel, and O&M procedures. These costs represent total plant investment, including all indirect costs. Capital costs are a function of boiler capacity, decreasing with increasing size. On a cost-effectiveness basis, this equates to less than $500/t of NO_2 removed. Operating costs have not yet been documented, but are expected to be small relative to costs reported for other technologies. Overall system costs—as with costs for any other combustion modification system—can be considerably higher if a long outage is required for the retrofit and replacement power must be purchased, or if boiler upgrades to accommodate the retrofit are included. The ongoing demonstration projects listed in Table I will help quantify retrofit applicability under site-specific conditions for each of the four major types of conventional coal-fired boilers, and thereby assist in determining the percentage of the U.S. boiler population potentially appropriate for retrofit.

The largest demonstration of LNB with OFA on a tangentially fired utility boiler is currently under way at the Kansas Power and Light Co.'s (KPL) Lawrence Energy Center unit 5, a 350-MW single-furnace boiler burning a highly reactive, low-slagging Midwestern bituminous pulverized coal.[10] Sponsored by EPRI, KPL, and the Kansas Electric Utilities Research Program, this testing uses CE's PM firing system. Testing with OFA flows ranging from, 0 to 25 percent at KPL confirms that OFA plays the dominant role in NO_x reduction. In addition, the PM firing system demonstrated minimal impact on boiler thermal performance.

Figure 1 compares preretrofit and postretrofit NO_x emissions data obtained in the KPL testing. As can be seen, NO_x reduction potential is greater at higher loads, with reductions of 30 to 50 percent above 200 MW. The KPL testing also showed that for the greatest NO_x reductions, an increase in excess O_2 was required to avoid CO emissions above 100 to 200 ppm. At 2.5 to 2.7 percent excess O_2, NO_x emissions at high load were approximately 180 to 220 ppm. Similar NO_x reductions were not possible at lower loads.

Comparable NO_x reductions with combustion modifications were experienced on various pulverized coal-fired boilers in demonstrations in both Europe and Japan. A paper presented by the Central Electricity Generating Board (CEGB) in England reported 30 to 50 percent NO_x reduction with FW's CF/SF burner—from 600 to 800 ppm preretrofit to 400 ppm postretrofit—on a 500-MW opposed-fired FW boiler.[11] However, an increase in CO emissions and unburned carbon on boiler sidewalls was reported. A representative of Babcock Hitachi (BHK) in Japan reported 30 percent NO_x reduction with retrofit of its HT-NR burner on a 350-MW wall-fired boiler burning a blend of high volatile bituminous Japanese coal and lower volatile bituminous Canadian coal, and originally equipped with OFA and dual register burners.[12]

A more extensive LNB retrofit was announced by Arizona Public Service Co. at the Four Corners station on an 800-MW wall-fired B&W boiler originally configured with three-nozzle cell burners.[13] This work is being conducted by FW and involves reconfiguring portions of the water walls to remove the cell burners and permit uniform placement of the new LNBs. Estimated cost for the project, which includes other upgrades, is $17.5 million (about $22/kW).

Achievable NO_x reductions for new boilers subject to New Source Performance Standards (NSPS) appear to be 0.15 to 0.20 lb/MBtu, as reported in 1987.[1] No major new developments were reported in this area. Separately,

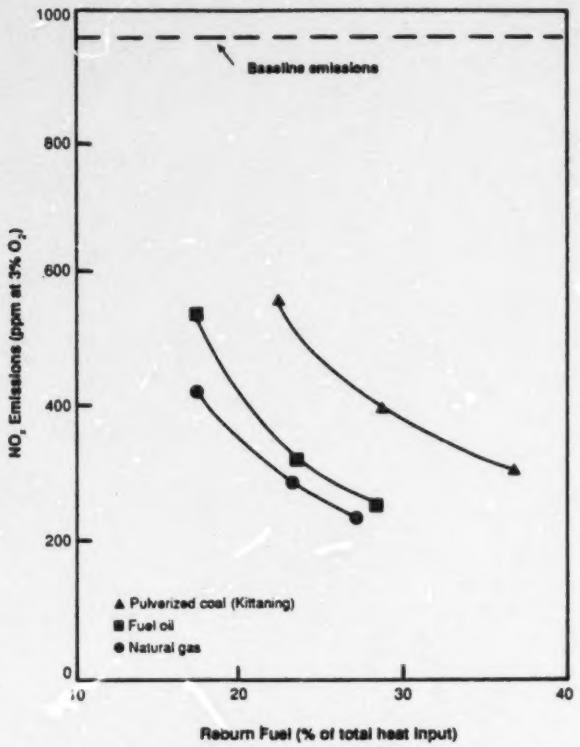

Figure 2. Tests in a pilot-scale cyclone boiler showed that reburning could reduce NO_x emissions by over 50% from the baseline level with a variety of reburn fuels. The boiler load for the tests was 6 MBtu/h, with a cyclone stoichiometry of 1.1 and 15% excess air. Source: Electric Power Research Institute.

however, and for both new and retrofit applications, it was reported that coal fineness can play a role in NO_x reduction by reducing unburned carbon, thereby allowing operation at lower O_2 levels.[14]

Advanced Technologies

Although LNB with OFA is the preferred approach for low-NO_x combustion modification on tangentially fired and wall-fired boilers, some investigations are being made to supplement these controls with advanced technologies that, in pilot testing, have shown the potential for greater NO_x reductions. This work is currently focusing on reburning and advanced OFA, as well as—internationally—flue gas recirculation (FGR) and burners out of service (BOOS).

Pilot-scale results and some field testing with reburning in combination with LNB with OFA have shown the potential for NO_x reductions approaching 75 percent. A full-scale investigation in West Germany with LNB, FGR, BOOS, and reburning using the fines from the pulverizer on a tangentially fired boiler burning high-moisture German brown coal indicates NO_x reductions of 65 percent, but at a significantly greater cost than LNB with OFA alone.[15]

Cyclone-fired Boilers

The configuration of cyclone boilers prevents retrofit with LNB. As a result, NO_x control efforts on these units have focused on other technologies, specifically reburning. Figure 2 shows data obtained by B&W in studies sponsored by EPRI and the Gas Research Institute (GRI) using a pilot-scale cyclone boiler. As these data indicate, reburning with coal, fuel oil, and natural gas can achieve NO_x reductions of 50 to 75 percent—from a baseline of about 1000 ppm (representative of the low end of uncontrolled NO_x emissions from cyclone-fired boilers) to as low as about 250 ppm.[16] Reductions of 40 to 50 percent are more likely in field applications. Retrofit capital cost estimates for reburning range from $25 to $45/kW. Operating costs range from 1 to 5 mills/kWh, depending on the type of reburn fuel used and the differential cost of that fuel relative to coal.

Based on these and other promising data, two major demonstrations are planned: one using gas as the reburn fuel, a project cofunded by EPRI, GRI, EPA, and the Ohio Coal Development Office at Ohio Edison's Niles plant, a 110-MW cyclone boiler burning Kittaning coal; and one using coal as the reburn fuel, a CCT-2 project cofunded by B&W, Wisconsin Power & Light Co. (WPL), and EPRI at WPL's Nelson Dewey station, a 100-MW cyclone boiler burning a 2 percent S midwestern bituminous coal.

Because gas has higher volatility than coal and contains no nitrogen, it is the preferred reburn fuel from a technical perspective. However, gas is a premium fuel, and use of coal would be simpler and less costly at plants where coal is already the primary fuel. Major retrofit issues to be assessed in these demonstrations include the potential impacts of reburning on overall boiler thermal performance, the ability to achieve good carbon burnout with coal reburning, and the effects of substoichiometric conditions in the reburn zone on furnace corrosion.

Postcombustion Controls for Coal-fired Boilers

The most developed and widely applied postcombustion NO_x control technology is selective catalytic reduction (SCR). Promising results are also being achieved with selective noncatalytic reduction (SNCR).

Selective Catalytic Reduction

Extensive operating experience has been gained with SCR in Japan and western Europe, where NO_x emission limits as low as 50 ppm have been mandated. In Europe, over 30,000 MW of coal-fired generating capacity will be equipped with SCR by 1990.[17] In Japan, over 6000 MW of SCR are presently installed on coal-fired boilers, with an additional 10,000 MW on gas- and oil-fired boilers. European and Japanese experience is predominantly with hot-side, high-dust applications (i.e., the SCR reactor is located between the economizer exit and the air heater inlet ahead of the particulate control device).

Retrofit SCR installations in these countries are generally designed to provide NO_x removals of 60 to 80 percent with residual NH_3 slips of less than 5 ppm—usually 1 to 2 ppm. With few exceptions, these design targets are being met. However, all applications are on coals with alkaline ash and sulfur contents of less than 1 percent: West German coal from the Ruhr and Saar

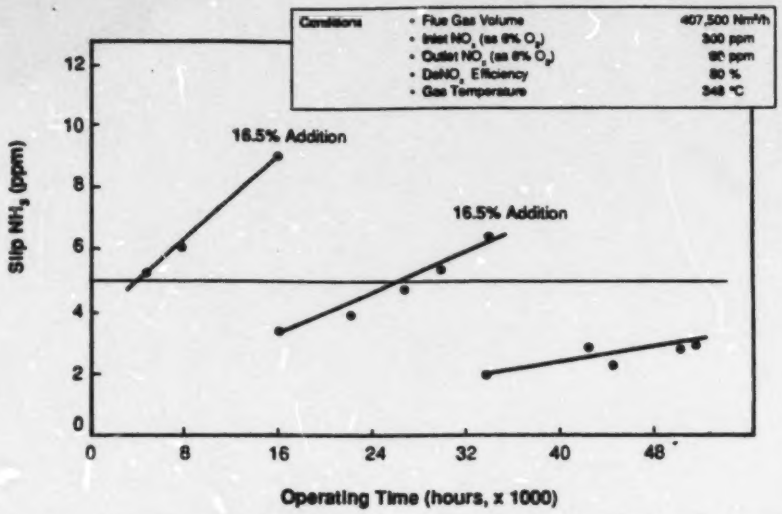
Conditions
• Flue Gas Volume 407,500 Nm³/h
• Inlet NO_x (as 6% O_2) 300 ppm
• Outlet NO_x (as 6% O_2) 90 ppm
• DeNO$_x$ Efficiency 80 %
• Gas Temperature 348 °C
16.5% Addition
16.5% Addition
Slip NH_3 (ppm)
Operating Time (hours, x 1000)

Figure 3. Effect of fresh catalyst additions on NH_3 slip in an operating SCR reactor. Initial catalyst quantity = 174 m³; total after fresh catalyst additions = 232 m³. All data measured by EPDC method. Source: Electric Power Development Company, Japan.

regions, and Polish, Chinese, and Australian coals.

Systems use either plate or honeycomb catalyst geometries, depending on space available for the reactor retrofit (honeycomb reactors are smaller), and flue gas pressure drop limits (plate reactors have a lower pressure drop).[18] Most of the installations report that catalyst space velocities of 2000 to 2500/h are necessary to achieve target NO_x removals and residual NH_3 slips. Since catalyst costs dominate SCR system costs, space velocity is a prime indicator of overall costs. Because of competition in Europe, catalyst costs there have recently come down from greater than \$900/ft³ to \$300/ft³ (typical costs are now \$300/ft³ to \$350/ft³).

Experience in both Europe and Japan confirms earlier assessments that the least-cost approach for meeting stringent NO_x emissions limits is to reduce NO_x as far as practical with combustion modifications before adding SCR. This practice also reduces pressure on the SCR system, allowing the catalyst to operate longer before needing replacement.

Several utilities and one process vendor reported on the effect of catalyst changeout/management strategies on catalyst replacement requirements.[18-20] Almost all SCR reactors abroad are designed with excess volume so that additional, fresh catalyst can be installed after several years of operation. This capability allows operators to extend the useful life of the original catalyst and represents insurance in the event of an unanticipated decrease in the activity of in-place catalyst.

Figure 3 shows how catalyst additions over time can be used to maintain residual NH_3 at acceptable levels. These data were taken by the Electric Power Development Co. (EPDC), a Japanese utility, using a BHK system at EPDC's Takehara unit 1. Similar examples were discussed from West Germany and Austria.

Special precautions can also be required to maintain catalyst activity. Austrian utilities operating the Durnrohr power station near Vienna reported that under their catalyst supplier's process guarantee they were required to maintain relative humidity in the reactor below 55 percent during plant shutdown. This was needed to prevent moisture from coming into contact with the catalyst and poisoning it, and is accomplished using a lithium-chloride dryer.

As an aid in predicting catalyst lifetimes, many utilities operating SCR reactors reported conducting bench-scale tests of catalyst samples extracted from full-scale reactors. Figure 4 shows reduction in catalyst activity monitored by a West German utility over approximately 17,000 hours of operation. Data such as these can be used to predict the extent of decays in catalyst activity and to schedule replacements. Some utilities reported that lifetime guarantees are negotiated with the process supplier in terms of catalyst activity measured by bench-scale tests, rather than by full-scale process performance. This procedure reportedly improves the precision with which judgments of process performance can be made.

Continuing work to develop catalysts resistant to poisoning by arsenic, potassium, and other trace elements was also reported.[21] Investigations here include structuring catalyst pore size to minimize the migration of these species to active sites. Other developments discussed included catalytic fabric filters, low-temperature SCR, and molecular sieve catalysts.

SCR System Costs

Capital costs for retrofit hot-side SCR installations operating in Europe were reported between \$60 and \$180/kW, averaging approximately \$125/kW. This broad range reflects the wide variability in unit sizes, initial and controlled NO_x concentrations, fuel properties, room available for installation, and other factors.

These costs bracket estimates for hypothetical retrofit SCR installations reported by both EPRI and EPDC. An EPRI-sponsored study estimates capital costs for SCR retrofits to a 500-MW wall-fired boiler at \$100/kW.[22] Figure 5 gives a breakdown of this estimate. EPDC estimates for SCR on a new 400-MW tangentially fired or wall-fired boiler were \$71/kW.[20] In that approximately \$20/kW in the EPRI estimate is attributable specifically to retrofit considerations, these two estimates are within approximately 10 percent of one another.

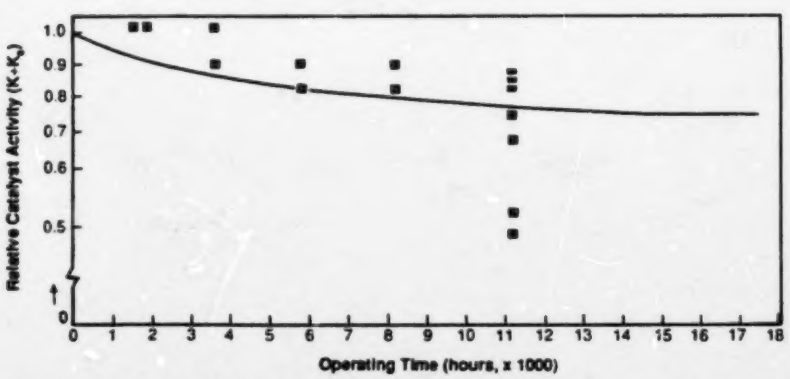

Figure 4. Reduction in catalyst activity in an SCR application in West Germany over approximately 17,000 hours of operation. Source: Neckarwerke, Federal Republic of Germany.

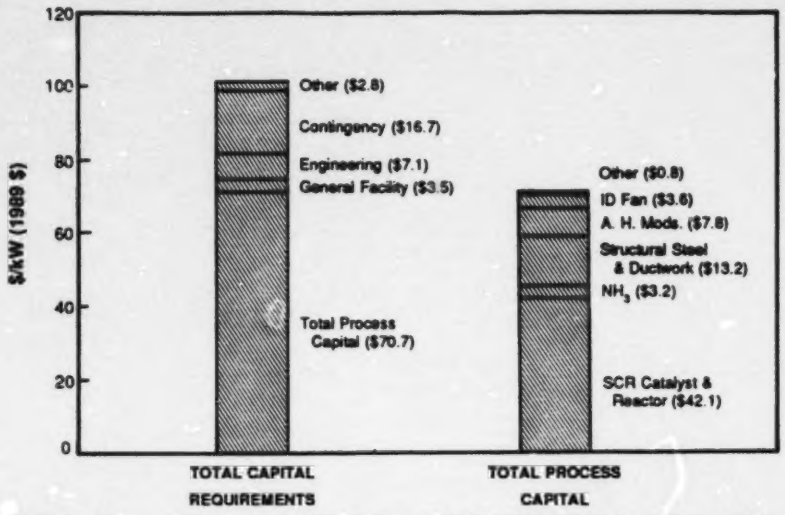

Figure 5. Estimates of capital costs for SCR retrofit to a 500-MW wall-fired boiler. Source: Electric Power Research Institute.

Corresponding levelized cost projections from both EPRI and EPDC estimates ranged from 4 to 9 mills/kWh, depending largely on the assumption used for catalyst cost and life. The lower value assumes catalyst costs of $330/ft^3 and a 4-year life, whereas the higher value reflects catalyst costs of $660/ft^3 and a 2-year life. These estimates correspond to control costs of $2000 to $4000/t NO_2 removed for typical pulverized-coal boilers based on a 65 percent capacity factor. With cyclone equipped boilers, which are inherently high NO_x emitters, SCR may be cost-competitive with other control options under development because it can remove large quantities of NO_x. For example, if the $330/ft^3 catalyst cost and 2-year life assumptions hold in actual practice, SCR control costs on cyclones could be as low as $600 to $700/t NO_2 removed.

SCR Assessment in the United States

Although SCR experience abroad has been impressive, several issues remain to be resolved regarding extrapolation of results to the United States. Key among these is applicability to medium- and high-sulfur coals. Among other potential concerns, and as reported in experience in West Germany, NH_3 absorbed by fly ash can lower the resale value of the ash.[19]

Two domestic pilot programs are being initiated to assess these and other potential problems. EPRI is sponsoring a bench- and pilot-scale program to assess SCR process design, catalyst life, instrumentation and controls, and plant integration issues. These investigations will involve up to six utilities burning a wide variety of coals. In the other program, Southern Company Services is hosting a CCT-2 demonstration project cofunded by EPRI to address similar technical issues, but with the focus on evaluating a large number of different catalysts. Together, these programs should provide the necessary experience to assess the feasibility and cost of SCR for U.S. applications.

Selective Noncatalytic Reduction

SNCR technologies using aqueous urea are receiving increased attention in the United States and Europe. Full-scale tests using urea show the potential for 30 to 50 percent NO_x reduction, and perhaps up to 70 percent, with NH_3 slip below 5 to 10 ppm. Estimated capital and operating costs for urea injection are approximately $5 to $15/kW and less than 3 to 4 mills/kWh, respectively. No papers were presented on NH_3 injection.

SNCR systems are planned or scheduled to be in operation in Europe by 1990 on approximately 1600 MW of capacity firing mostly brown coal.[17] In the United States, full-scale investigations using urea injection are under way on a 110-MW gas- and oil-fired boiler operated by San Diego Gas & Electric Co. (SDG&E) at the Encina station. This project, cofunded by EPRI, has achieved up to 60 percent NO_x reduction under ideal conditions.[23] Additional tests are under way by Southern California Edison (SCE).

Other investigations by vendors involve optimizing mixing and reagent stoichiometry and shifting or broadening the optimum temperature range for injection (systems currently operate at between approximately 1600 and 2000°F). Work is also under way (and planned) to investigate additives to suppress NH_3 slip and to assess performance with multiple-level injection.

NO_x Controls on Oil- and Gas-fired Boilers

Substantial development activity on oil- and gas-fired boilers since the last symposium was reported by utilities and vendors in the United States and abroad. A prime reason for the increasing level of attention is that these units are often located in metropolitan areas where ozone nonattainment and health concerns associated with pollutant concentrations are especially sensitive issues.

A report on a survey of oil-fired boilers in Japan indicated that experience there has been favorable with SCR applied in combination with combustion controls.[24] NO_x removals of up to 80 percent were reported. However, many units in Japan are not required to achieve NO_x removals this high or operate at low loads. Moreover, since combustion modifications are in place, the SCR systems are often responsible for only a small portion of total NO_x reduction.

In the United States, electric utilities have taken the lead in applying controls on oil-fired boilers, especially in California where NO_x restrictions are tightest. These utility projects include three full-scale demonstrations currently under way by SCE, a full-scale demonstration planned by the Los Angeles Department of Water and Power (LADWP), and SDG&E's SNCR investigations. Development activity is also under way on the East coast, and an LNB with OFA retrofit conducted by Hawaiian Electric Co. (HECO) has been completed in Hawaii.

The HECO unit is a 150-MW face-fired boiler with preretrofit NO_x emissions of approximately 600 ppm. Windbox FGR and BOOS had already reduced this total by 50 percent; subsequent installation of LNB with OFA brought levels to below 150 ppm—an 80 percent reduction from uncontrolled levels.[25]

Prior to installation of LNB, some loss of load and operating flexibility had been experienced by HECO as a result of taking burners out of service. Addition of LNB allowed HECO to eliminate BOOS and regain the lost capacity and flexibility. As with LNB with OFA retrofits for coal-fired boilers

reported on at the conference, OFA was again the dominant factor in NO_x reduction.

One important finding reported by HECO was that particulate emissions from oil-fired boilers tend to increase with NO_x reductions. This trend, shown in Figure 6 in terms of opacity (which in this demonstration correlated directly with particulate emissions), has been masked in applications in Japan because oil-fired boilers there are required to have particulate controls. Based on this experience, which will likely be repeated in applications elsewhere in the United States, attention is being given to improving atomizer designs and to staging, so as to reduce NO_x without increasing particulate emissions.

Retrofit capital costs for the LNB with OFA system were $20 to $40/kW, two to three times higher than anticipated in papers presented at the 1987 symposium.[1] This higher cost was attributable to the purchase of a comprehensive low-NO_x retrofit package, and—as with the retrofits reported on coal-fired boilers—to plant upgrades (e.g., air and fuel systems, instrumentation and controls, and on-line monitoring) included as part of the retrofit.

Incineration

Various studies are under way to assess emissions of NO_x and other species from hazardous waste incineration (HWI) and municipal waste incineration (MWI). While these facilities do not contribute substantially to national NO_x emissions, emissions from individual plants may be sufficient to result in a local NO_x problem, thus preventing specific incineration facilities from being permitted.

A multiphase study to assess application of natural gas reburning for pollutant minimization (NO_x, CO, and total hydrocarbon emissions) in municipal waste incinerators was reported.[26] Initial tests on a 0.9-MW pilot-scale unit closely simulating full scale showed NO_x reductions up to 70 percent with 15 percent reburning and 4.0 to 5.2 seconds residence time in the reburning zone. Reductions of 50 to 60 percent with 15 percent reburning are possible at lower residence times (2.0 to 2.5 seconds).

Promising results have been obtained in tests to minimize NO_x emissions during incineration of a nitrogenated pesticide while maintaining high organic destruction.[27] Pilot-scale testing in a substoichiometric precombustion burner indicates that uncontrolled NO_x emissions of 4500 ppm are reduced to less than 150 ppm with controls. Pesticide destruction was high, greater than 99.99 percent, and CO and total hydrocarbon emissions were low, less than 15 ppm and 2 ppm, respectively. Several common products of incomplete combustion were measured in concentrations typically less than 10 ppb.

Results were also reported on experiments to examine NO_x emissions from a laboratory-scale rotary kiln incinerator burning nitrogenated wastes in batch mode.[26] Results here indicate that significant quantities of NO_x (up to 1000 ppm) can be formed during incineration of nitrogen containing solid wastes, and that conversion of fuel nitrogen to NO_x depends on nitrogen speciation and combustion conditions.

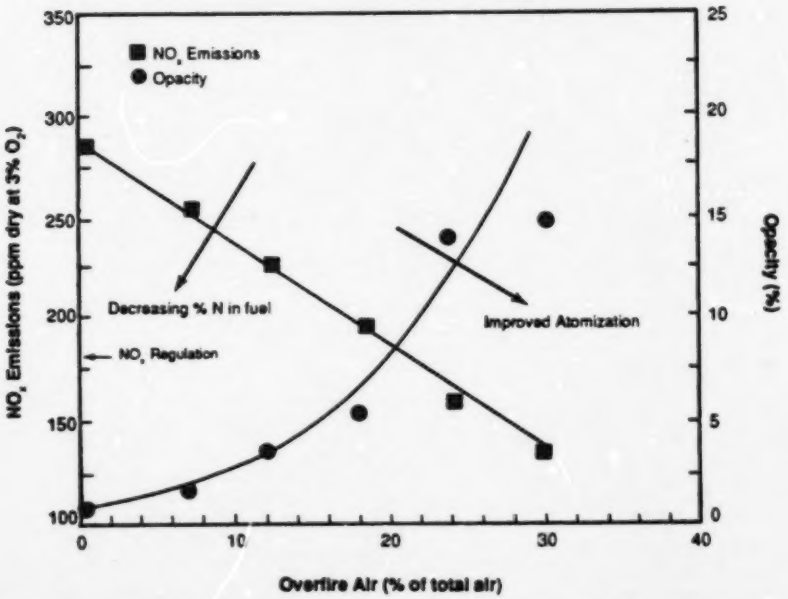

Figure 6. NO_x emissions and opacity trade-off data obtained at 135 MW on a 150-MW oil-fired boiler operated by the Hawaiian Electric Co. (0.3 N fuel oil; 12% FGR). Source: Hawaiian Electric Co. and Electric Power Technologies.

Fundamental Combustion Research

The number and diverse nature of papers presented on fundamental combustion research at the symposium indicate continuing interest in the development of techniques to predict and control NO_x at the source.

In one study, the ability to predict levels of fuel and thermal NO_x formation and destruction with air staging and reburning during the combustion of pulverized coal was demonstrated using computer modeling.[29] As part of this work, modeling results were compared to earlier experimental data and shown to compare favorably.

The potential for NO_x reduction operating with fuel-rich turbulent diffusion flames in boilers burning natural gas and methanol was evaluated in a pilot-scale combustion tunnel.[30] The combustion air was doped with NO in concentrations from zero to 3200 ppm. With 1600 ppm NO concentration, NO reductions in the fuel-rich natural gas and methanol flames were 93 and 76 percent, respectively. The data were compared to the Sandia chemical kinetic code which predicts a higher concentration of intermediate radicals with methane than with methanol, thus yielding greater NO_x reduction with methane for reburning applications. In another study, methanol injection downstream of the primary flame zone was evaluated as a means of controlling NO_x and SO_2. A theoretically predicted homogeneous gas-phase reaction was demonstrated in laboratory- and pilot-scale tests.[31] Methanol injected converts SO_3 to SO_2 and NO to NO_2 at temperatures greater than 700°C, making removal by wet scrubbing practical. This new approach might minimize corrosion and fouling when combined with SNCR technologies.

A study of the effect of pressure on fuel NO in laboratory-scale gasification of bituminous coal showed that increasing operating pressure from 1 to 2 atm caused NO to decrease from 230 to 12 ppm with minor dependence on residence time.[32] These results have potential significance for the operation of pressurized combustion systems, such as pressurized fluidized-bed combustors.

In another study, the evolution and reaction of fuel nitrogen during the rapid pyrolysis and combustion of coal was examined using Montana Rosebud subbituminous coal and Pittsburgh bituminous coal.[33] Rapid combustion of

most pyrolysis products occurs with the Montana coal, with little hydrocarbons, tar, or soot. Volatile fuel nitrogen reduction does not occur if confined to the thin volatile boundary layer around individual particles. The Pittsburgh bituminous yields significant tar with most of the fuel nitrogen in the tar. This portion of volatile nitrogen is removed from participation in any nitrogen reduction chemistry and thus may be an important pathway for fuel nitrogen conversion to NO_x.

In a similar study, fuel nitrogen mechanisms governing NO_x abatement were investigated for low- and high-rank coals using a laboratory-scale pulverized-coal combustor rated at 100,000 Btu/h.[34] Emphasis here was placed on determining the rates of destruction and conversion of nitrogenous species as a function of coal rank in the fuel-rich stage and in the burnout stage. Known gas-phase (not heterogeneous) reactions control destruction of NO and HCN. The reaction is first order in NO and NH_3. Late evolution of HCN is important in driving the gas-phase reactions destroying NO and other nitrogen compounds.

Reductions in NO_x and nitrogen species as a result of changing process variables in reburning were studied using an isothermal plug flow reactor.[35] Reburning with highly volatile bituminous coal resulted in NO_x reductions from 200 to 600 ppm to less than 50 ppm. Reburn fuel fraction, primary stoichiometry, temperature, and residence time were interdependent and significant parameters. Inlet NO_x concentration, coal type, and particle size were not significant at optimum conditions.

Conclusions

- Extensive research is currently under way to determine what effects, if any, NO_x emissions have on the environment. For example, direct N_2O emissions in flue gas from conventional pulverized coal-fired boilers, previously thought to affect stratospheric ozone, were shown to be less than estimated as a result of errors in the earlier measurements.
- There has been a dramatic increase in full-scale demonstrations of combustion modifications on pulverized coal-fired boilers, especially in the United States, West Germany, the United Kingdom, Italy, and Japan. This is in sharp contrast to previous symposia in this series, which focused principally on pilot developments. Increased development and demonstration activity in the United States is moving the United States into an increasingly important position as a supplier of combustion modification NO_x controls, both domestically and internationally.
- R&D to reduce NO_x emissions from stationary sources in the United States remains focused on retrofit combustion modifications for conventional pulverized coal-fired boilers. Application of LNB with OFA is the preferred approach for tangentially fired and wall-fired units. Experience to date with these technologies has shown NO_x reductions of up to 50 percent with little, if any, impact on boiler operation and maintenance. Overfire air has proven to dominate NO_x reduction in these applications, and may prove appropriate as a stand-alone option for up to 30 percent removal (and potentially above 30 percent with advanced systems) in some applications. Capital costs for LNB with OFA are in the range of \$10 to \$30/kW. Operating costs have not yet been documented, but are expected to be small relative to costs reported for other technologies. Reburning remains the only widely discussed combustion modification option for cyclone boilers, with the potential for NO_x reductions of 40 to 50 percent in field applications.
- Early demonstration experience indicates that utilities considering combustion modification NO_x controls are simultaneously assessing the need to upgrade other boiler systems, especially air and fuel supply systems and their controls. This "integrated approach" to NO_x control increases retrofit costs, but is prudent from an overall cost and efficiency standpoint. Moreover, it increases the possibility that desired NO_x reductions will, in fact, be achieved and maintained.
- R&D activity with postcombustion NO_x controls continues to focus on SCR. Over 30,000 MW of coal-fired generating capacity will be equipped with SCR in Europe by 1990, while in Japan 6000 MW of SCR is presently in place on coal-fired boilers. Retrofit installations in Europe and Japan typically achieve NO_x removals of 60 to 80 percent with residual NH_3 slips of less than 5 ppm—usually 1 to 2 ppm. Costs for actual retrofit hot-side installations in Europe are averaging approximately \$125/kW. These costs are consistent with EPRI capital cost estimates of \$100–\$125/kW for hypothetical retrofit installations. Levelized cost projections for both U.S. and Japanese installations are estimated at 4 to 9 mills/kWh.
- Experience in Europe and Japan confirms earlier assessments that the least-cost approach for meeting stringent NO_x emission limits is to reduce NO_x as far as practical with combustion modifications before adding SCR. This practice also reduces pressure on the SCR system, allowing the catalyst to operate longer before needing replacement.
- Although SCR experience abroad has been impressive, several issues remain to be resolved regarding extrapolation of results to the United States. Key among these is applicability to medium- and high-sulfur coals. Among other potential concerns, NH_3 absorbed by fly ash can lower the resale value of the ash. Research is being initiated in the United States to assess these and other issues.
- SNCR technologies are receiving increased attention in the United States and Europe. Results with urea injection show the potential for 30 to 50 percent NO_x reductions, and perhaps up to 70 percent, with NH_3 slip below 5 to 10 ppm. Capital and operating costs are estimated at approximately \$5 to \$15/kW and less than 3 to 4 mills/kWh, respectively.
- Substantial development activity is under way in the United States and abroad to optimize NO_x controls on oil- and gas-fired boilers. One important finding to date in a utility application in Hawaii is that particulate emissions from oil-fired boilers tend to increase with NO_x reductions. This trend has been masked in demonstrations in Japan because oil-fired boilers there are required to have particulate controls. Attention is being given to improving atomizer designs and to staging so as to reduce NO_x without increasing particulate emissions.

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